PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS) and National Emission Standards
for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

This permit supersedes your permit dated July 30, 2004, as amended
March 29, 2006, June 5, 2007, January 14, 2008, and September 15, 2009.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060
Registration No.: 81391
Plant ID No.: 51-187-0041

is authorized to construct and operate

an electric power generation facility

located at

Lots 3, 5, 6, 7, 8, 9, and 10, Warren Industrial Park
Warren County

in accordance with the Conditions of this permit.

Approved: **DRAFT**

Regional Director

Signature Date

Permit consists of 35 pages.
Permit Conditions 1 to 75.
Source Testing Report Format
Attachments A and B

Deleted: ~~Figure 1 and Appendix A~~

PERMIT CONDITIONS - the regulatory reference or authority for each condition is listed in parentheses ( ) after each condition. All parts per million (ppm) are parts per million by volume on a dry gas basis (ppmvd), corrected to 15 percent oxygen, unless otherwise stated. All heat inputs in British thermal units (Btu) are based on higher heating values.

INTRODUCTION

This permit approval is based on the permit applications dated January 7, 2010, January 18, 2010, February 12, 2010, March 16, 2010, April 14, 2010, April 23, 2010, June 24, 2010, July 2, 2010, July 27, 2010, August 6, 2010, August 24, 2010, August 27, 2010, September 1, 2010 (2 items), September 2, 2010, and September 24, 2010 and supplemental information dated April 27, 2010 and May 20, 2010. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. **Equipment List**

   Equipment to be constructed at this facility consists of:

   - three combined-cycle power generating units (T-1, T-2, & T-3) where each unit includes the following emission units:

- one Mitsubishi natural gas-fired combustion turbine (CT) generator, Model M501 GAC, rated at 299,600 kW and 2,996 million Btu per hour heat input (CT-1, CT-2, & CT-3) (NSPS Subpart KKKK); and
- one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1, DB2, & DB3) (NSPS Subpart KKKK);

– one natural gas-fired auxiliary boiler, rated at 88.1 million Btu per hour heat input (B-1) (NSPS Subpart Dc);

– one natural gas-fired fuel gas heater, rated at 52.0 million Btu per hour heat input (GH-1) (NSPS Subpart Dc);

– one diesel-fired emergency generator, rated at 2,193 HP (EG-1) (NSPS Subpart IIII and 40 CFR 63 Subpart ZZZZ);

– one diesel-fired emergency fire water pump, rated at 2.3 million Btu per hour heat input (FWP-1) (NSPS Subpart IIII and 40 CFR 63 Subpart ZZZZ);

– three turbine inlet chillers (600,000 gal/hr each) (IC-1, IC-2, & IC-3); and

– one 6,000 gallon distillate oil storage tank (ST-1).

(9 VAC 5-80-1100 and 9 VAC 5-80-1605 A)

PROCESS REQUIREMENTS – COMBINED-CYCLE UNITS (T-1, T-2, & T-3)

2. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by use of a two-stage, lean pre-mix dry low-NO_x combustor, a selective catalytic reduction (SCR) control system using ammonia injection, and good combustion practices. The SCR system shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

3. **Emission Controls: Carbon Monoxide** – Carbon monoxide (CO) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

4. **Emission Controls: Volatile Organic Compounds** – Volatile Organic Compound (VOC) emissions from each CT (CT-1, CT-2, & CT-3) and HRSG duct burner (DB1, DB2, & DB3) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 18).
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

5. **Monitoring Devices: SCR** - Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate, gas stream flow rate, and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, and 9 VAC 5-80-1705 B)

6. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, and 9 VAC 5-80-1705 B)

7. **Monitoring Device Observation: SCR** – The devices used to continuously measure ammonia feed rate, gas stream flow rate, and SCR catalyst bed inlet gas temperature shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

8. **Monitoring Device Observation: Oxidation Catalyst** - The devices used to continuously measure catalyst bed inlet and outlet gas temperatures for each oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

PROCESS REQUIREMENTS - EMERGENCY UNITS (EG-1 & FWP-1)

9. **Monitoring Devices** – The permittee must install a non-resettable hour meter on the emergency generator (EG-1) and the emergency fire water pump (FWP-1) prior to the

startup of each unit. The hour meters shall be provided with adequate access for inspection.
(9 VAC 5-80-1180 D and 40 CFR 60.4209)

10. **Maintenance and Operation** – The permittee must maintain and operate the emergency generator (EG-1) and the emergency fire water pump (FWP-1) according to the manufacturer's written instructions, or procedures developed by the permittee that are approved by the manufacturer, over the entire life of the engine. In addition, the permittee may only change those settings that are approved by the manufacturer.
(9 VAC 5-80-1180, 9 VAC 5-50-260, 40 CFR 60.4206 and 40 CFR 60.4211)

PROCESS REQUIREMENTS - AUXILIARY BOILER (B-1) and FUEL GAS HEATER (GH-1)

11. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from the auxiliary boiler (B-1) and the fuel gas heater (GH-1) shall be controlled by ultra low-NO_x burners.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1705 B)

12. **Emission Controls: Carbon Monoxide and Volatile Organic Compounds** - CO and VOC emissions from the auxiliary boiler (B-1) and the fuel gas heater (GH-1) shall be controlled by good combustion practices, operator training and proper emissions unit design, construction and maintenance. Boiler and heater operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boiler and heater. These procedures shall be based on the manufacturer's recommendations, at minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

OPERATING/EMISSION LIMITATIONS – COMBINED-CYCLE UNITS (T-1, T-2, & T-3)

13. **Fuel** - The approved fuel for each CT (CT-1, CT-2, & CT-3) and each HRSG duct burner (DB1, DB2, & DB3) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR 72.2. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 9 VAC 5-50-260, and 40 CFR 60.4330(a)(2))

14. **Fuel Throughput** – The combustion turbines (CT-1, CT-2, & CT-3) and duct burners (DB1, DB2, & DB3) combined shall consume no more than 90,073 x 10^6 scf of natural

gas per year. Throughput shall be calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

15. **Fuel Monitoring** – The permittee shall use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas being fired at the electric power generation facility is 0.0003 percent by weight or less (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet), to demonstrate that potential sulfur dioxide emissions shall not exceed the limits specified in Condition 16.

If the permittee elects not to demonstrate the sulfur content using the above option, the permittee may:

a. determine and record the total sulfur content of the natural gas once per unit operating day or

b. develop custom schedules for determination of the total sulfur content of the natural gas, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

(9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.4365(a), 40 CFR 60.4370(b) and 40 CFR 60.4370(c))

16. **Short-Term Emission Limits** - Emissions from the operation of each combined-cycle power generating unit (T-1, T-2, & T-3) shall not exceed the limits specified below:

	Short term emission limits
PM-10 (includes condensable PM)	▪ 8.0 lb/hr without duct burner firing ▪ 14.0 lb/hr with duct burner firing ▪ 0.0027 lb/MMBtu without duct burner firing ▪ 0.0040 lb/MMBtu with duct burner firing
PM-2.5	▪ 8.0 lb/hr without duct burner firing ▪ 14.0 lb/hr with duct burner firing ▪ 0.0027 lb/MMBtu without duct burner firing ▪ 0.0040 lb/MMBtu with duct burner firing
Sulfur dioxide	▪ 0.98 lb/hr ▪ 0.00028 lb/MMBtu
Oxides of nitrogen (as NO_2)	▪ 25.3 lb/hr ▪ 2.0 ppmvd
Carbon monoxide	▪ 9.9 lb/hr and 1.5 ppmvd without duct burner firing ▪ 17.4 lb/hr and 2.4 ppmvd with duct burner firing

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Volatile organic compounds	▪ 2.6 lb/hr and 0.7 ppmvd without duct burner firing ▪ 6.1 lb/hr and 1.6 ppmvd with duct burner firing
Sulfuric acid mist (H_2SO_4)	▪ 0.00013 lb/MMBtu without duct burner firing ▪ 0.00025 lb/MMBtu with duct burner firing

Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides and carbon monoxide, which shall be calculated as a one-hour average.

Unless otherwise specified, limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 18 of this permit.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 2, 3, 4, 13, and 43.

This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Condition 52 of this permit.

(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 40 CFR 60.4320, and 40 CFR 60.4330)

17. **Annual Emission Limits** – Total emissions from the operation of all three combined-cycle power generating units (T-1, T-2, & T-3) including duct burners shall not exceed the limits specified below:

Pollutant	Annual Emissions (tons)
PM-10 (includes condensable PM)	159.1
PM-2.5	159.1
Sulfur Dioxide	12.3
Oxides of Nitrogen (as NO_2)	317.7
Carbon Monoxide	348.6
Volatile Organic Compounds	181.0
Sulfuric Acid Mist (H_2SO_4)	9.5

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* This permit may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in Condition 52 of this permit.

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 2, 3, 4, 13, 14, and 43.
(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

18. **Startup/Shutdown** – The short-term emission limits contained in Condition 16 apply at all times except during periods of startup and shutdown.

a. Startup and shutdown periods are defined as follows:

i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emissions limits for cold startup periods shall not exceed 4.2 hours per occurrence.

ii. Warm Startup – refers to restarts made more than 8 but less than 72 hours after shutdown. Exclusion from the short-term emissions limits for warm startup periods shall not exceed 2.1 hours per occurrence.

iii. Hot Startup – refers to restarts made 8 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed 1.5 hours per occurrence.

iv. Shutdown – refers to the period between the time the turbine load drops below 60 percent operating level and the fuel supply to the turbine is cut. Exclusion from the short-term emissions limits for shutdown shall not exceed 0.5 hours per occurrence.

b. The permittee shall operate the Continuous Emission Monitoring Systems (CEMS) during periods of startup and shutdown.

c. The permittee shall record the time, date and duration of each startup and shutdown period.

d. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

(9 VAC 5-50-260, 9 VAC 5-80-1715, 9 VAC 5-80-1180, and 9 VAC 5-80-1705)

19. **Emission Limits: Duct Burners** – Emissions from the operation of each duct burner (DB1, DB2, & DB3) operating independently of each combined-cycle system (T-1, T-2, & T-3) shall not exceed 54 ppm of oxides of nitrogen (expressed as NO_2) at 15 percent O_2.
(9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.4320)

20. **Duct Burner Operational Restriction** – The duct burners (DB1, DB2, & DB3) shall not operate between the hours of 10 p.m. and 5 a.m. Eastern Standard Time (EST) during the period between September 1st and April 30th, except that the duct burners may be operated during a Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) Independent System Operator's (ISO) declared emergency. This duct burner operational restriction is included to demonstrate that the project will not cause or contribute to an exceedance of the applicable PM-2.5 PSD Class I increment as of the trigger date, October 20, 2011.
(9 VAC 5-80-1180, Virginia Code 10.1 1307.02., and Virginia Code 10.1-1307.3 A.5.)

21. **Pollution Prevention: Ammonia** – Emissions of ammonia resulting from unreacted ammonia emitted from the SCR (ammonia slip) shall not exceed 2 ppmvd during steady-state conditions and 5 ppmvd during non-steady-state operations. Compliance with the ammonia slip limit shall be determined based on a one-hour block average. Steady-state operation is based on a steady load for the duration of the CEMs hour and is defined as less than a 5% rate of load change within the hour. At least three months prior to startup, the permittee shall submit a plan for approval for monitoring the ammonia slip and demonstrating compliance with the ammonia slip limit from each SCR system to the DEQ. Implementation of the plan shall commence upon startup of the facility. The permittee shall demonstrate compliance with the ammonia slip limit at least 95% of the time the SCR is operating. Compliance with the 95% time percentage requirement shall be calculated daily and based on a 30-day rolling period. Alternatively, if on a given day less than 100 hours of operation has occurred in the prior 30 days, compliance with the 95 percent limits may be based on the most recent 100 hours of SCR operation.
(9 VAC 5-80-1180, 9 VAC 5-170-160, and Virginia Pollution Prevention Act, § 10.1-1425.11)

22. **Visible Emission Limit -** Visible emissions from each combined-cycle (T-1, T-2, & T-3) stack shall not exceed 10 percent opacity, except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown (as defined in Condition 18), and malfunction.
(9 VAC 5-50-20, 9 VAC 5-50-260, and 9 VAC 5-80-1705)

23. **Requirements by Reference -** Except where this permit is more restrictive than the applicable requirement, the CTs (CT-1, CT-2, & CT-3) and duct burners (DB1, DB2, & DB3) as described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

AIR QUALITY RELATED VALUES

24. **Source Reductions and Emission Offsets** – The permittee shall implement the following actions to secure a total of emission offsets equal to the Total Annual NO_x Limit, (i.e. the sum of NO_x limits for the combustion turbines, duct burners and emergency engines in Conditions 17, 30, 31, 39, and 40) ("TANL") at the Facility. The National Park Service has determined that for the Warren County Power Station these actions provide full mitigation or acceptable net environmental benefits for all potential or actual adverse impacts to Air Quality Related Values, including visibility and aquatic resources, at Shenandoah National Park (SNP).

   a. Definitions – Solely for the purposes of this permit Condition 24, the following definitions shall apply:

      i. "Emissions Offsets" means Emission Reduction Credits, Allowances under the Acid Rain Program or other emissions reductions that are obtained to mitigate potential impacts of the permitted facility on the air quality and related values in SNP.

      ii. "Eligible SO_2 Allowances" mean those Allowances (as defined in the Clean Air Act, section 402(3)) that originate from Dominion owned facilities in the region shown on Attachment A ("Originating Account").

      iii. "Eligible NO_x Allowances" mean any NO_x Allowances as that term is defined in a federally-approved NO_x emissions trading program.

      iv. "Facility NO_x Emission Ton" means each ton of NO_x emissions from the permitted facility.

      v. "Allowable Annual NO_x Emissions" means 330.7 tons NO_x per year, which represents the maximum Facility NO_x Emission Tons authorized under the permit.

      vi. "Emissions Reduction Credits" means the number of tons per year of creditable emissions reductions.

      vii. "Offset Ratio" means the ratios shown on the map at Attachment A.

   b. Emission Offsets from specific facilities – The permittee shall secure a reduction in emissions from a source or sources in the manner prescribed as follows:

      i. The permittee shall permanently cease all permitted SO_2 and NO_x emissions at North Branch Power Station in Grant County, West Virginia. Based on the actual emissions in 2007-2008 and the distance and direction of North Branch Power Station from the Park these reductions shall result in an Emission Offset of 243 TPY toward the TANL offset requirement. Neither the permitted nor actual SO_2

and NO_x emission reductions from the North Branch Power Station may be used as Emissions Offsets for any other purpose.

ii. The permittee shall retire permanently the 175 TPY of NO_x offsets procured from World Kitchen in Martinsburg, West Virginia approved by the DEQ by letter of 11/17/07. Based on the distance and direction of World Kitchen from the Park, this retirement of emission reduction credits shall result in 17.5 TPY emission offsets toward the TANL requirement.

c. Allowances or Emission Reduction Credits retirements

The permittee shall secure and retire Eligible SO_2 Allowances, Eligible NO_x Allowances, or Emission Reduction Credits in the amount equivalent to 70.2 TPY of Emission Offsets toward the TANL requirement by a combination of the following.

i. Retire Eligible SO_2 Allowances or Eligible NO_x Allowances by transferring them from the Originating Account each year (by making the appropriate designation(s) in the Allowance Tracking System transfer form) into an account administered by the U.S. EPA for the Acid Rain Program to be identified by the DEQ.

(a) To ensure that Eligible SO_2 Allowance or Eligible NO_x Allowance retirements benefit air quality and related values in SNP, any such Allowance that originates from facilities located in an area with an Offset Ratio (from the Attachment A map) higher than 10:1 shall require retirement of an additional ten percent of Eligible SO_2 Allowances or Eligible NO_x Allowances in order to offset one Facility NO_x Emission Ton. For example, Eligible SO_2 Allowances that originate from the 20:1 Offset Ratio area shall be retired at the rate of 22:1; Eligible SO_2 Allowances that originate from the 30:1 Offset Ratio area shall be retired at the rate of 33:1; and Eligible SO_2 Allowances that originate from the 40:1 Offset Ratio area shall be retired at the rate of 44:1 until all of the Allowable Annual NO_x Emissions are offset.

(b) The permittee is prohibited from replenishing or causing to be replenished those retired allowances in the Originating Account of the specific Dominion unit that the allowances originated from, by securing, purchasing or otherwise acquiring allowances from any other accounts and transferring them into that Originating Account. After the date of initial operation, the only allowances that can be placed in that account are those allocated by EPA to that account of a vintage year of and after startup of the equipment listed in Condition 1.

ii. Secure and retire Emission Reduction Credits multiplied by the Offset Ratio of the plant location shown on Attachment A.

iii. The requirements of c.i. and ii. in equation form are:

(Eligible SO_2 or NO_x Allowance$_{\text{Plant in area of 10:1 Offset Ratio or less}}$/Offset Ratio) +

(Eligible SO_2 or NO_x Allowance$_{\text{Plant in area greater than 10:1 Offset Ratio}}$/(1.1x Offset Ratio))

$\geq 70.2 - \sum (ERC_{Plant}/\text{Offset Ratio})$

d. Procedure and timing.

i. The actions in items Condition 24 b. and c. shall be completed and in effect prior to startup of the equipment listed in Condition 1.

ii. Prior to startup of the equipment listed in Condition 1, the permittee shall provide to the DEQ written documentation from the air pollution control agency that regulates each of the sources identified in 24 b. and c.ii. that the requirements of Condition 24 b. and c.ii. (if that option is selected) have been met and that the emission reductions are recognized by the agency as creditable, permanent, and federally enforceable. The document shall state that the emissions reduction has not been and will not be credited toward another reduction requirement. The facility shall not commence operation until the DEQ has approved in writing the documentation submitted by the permittee pursuant to this subsection as satisfying the requirements of Condition 24 b. and c.ii. (if that option is selected).

iii. The permittee shall submit a report to the DEQ prior to the commencement of operation of the permitted facility that demonstrates that the Allowances have been retired in accordance with Condition 24.c.i. Annual reports demonstrating compliance with the retirement obligations and prohibition on replenishment in Condition 24 c. i. must be submitted to the DEQ within 90 days of the end of each calendar year (i.e. 30 days after the compliance deadline under the Acid Rain Program). These reports shall continue to be required for the life of the facility or until all obligations under this permit condition are satisfied with permanent emission reductions. To the extent the permittee accepts federally enforceable limitations on the Total Annual NO_x Emissions in the future, the permittee will only be required to retire Eligible SO_2 Allowances or ERCs such that the sum of the retired allowances at a plant multiplied by that plant's Offset Ratio is equal to the new Total Annual NO_x Emissions minus 260.5. All reports shall be sent to the DEQ, and

Superintendent
Shenandoah National Park
3655 U.S. Highway 211 East
Luray, VA 22835

At any time, but after at least 30 days notice to the public and the Federal Land Manager, the DEQ, in consultation with the Federal Land Manager, may approve an alternative

mitigation plan proposed by the permittee in lieu of this condition. At a minimum, such a plan shall result in actual sulfur dioxide or nitrogen oxides reductions from an existing stationary source(s) within one of the areas identified in Attachments A and B of at least the Allowable Annual NO_x Emissions multiplied by the corresponding Offset Ratio. Such reductions must be practically enforceable, permanent, and quantifiable, and must be created after January 19, 2010. The reductions must result in the same or greater reduction in impacts to aquatic resources and visibility to the SNP as the retirements of allowances outlined in paragraphs a through c of this condition.
(9 VAC 5-170-160, 9 VAC 5-80-1180, and 9 VAC 5-80-1985 E)

OPERATING/EMISSION LIMITATIONS – EMERGENCY UNITS (EG-1 & FWP-1)

25. **Fuel** – The approved fuel for the emergency generator (EG-1) and the emergency fire water pump (FWP-1) is distillate fuel oil with a maximum sulfur content per shipment of 0.0015 percent by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 40 CFR 60.4207(b), and 40 CFR 80.510(b))

26. **Operating Hours: Emergency Fire Water Pump** - The emergency fire water pump (FWP-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. The emergency fire water pump (FWP-1) shall not be operated for testing and/or maintenance during startup of any of the combined-cycle units (T-1, T-2, or T-3), as defined by Condition 18. The periodic testing of the emergency fire water pump shall be restricted to only the daylight hours between 9:00 AM and 5:00 PM eastern standard time (EST).
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

27. **Operating Hours: Emergency Generator** - The emergency generator (EG-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. The emergency generator (EG-1) shall not be operated for testing and/or maintenance during startup of any of the combined-cycle units (T-1, T-2, or T-3), as defined by Condition 18. The periodic testing of the emergency generator shall be restricted to only the daylight hours between 9:00 AM and 5:00 PM eastern standard time (EST).
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

28. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:

Deleted: **Source Reductions and Emission Offsets** – For the purposes of mitigating potential air quality impacts on Air Quality Related Values (AQRVs) at the Shenandoah National Park Class I Area in Virginia, including visibility and acid deposition, the permittee shall implement the following:¶
¶
Level 1¶
<#>Acid Deposition Offsets – The permittee shall secure a reduction in emissions contributing to acid deposition from a source or sources in the manner prescribed as follows:¶
¶
<#>At a minimum, the permittee shall secure NO_x emissions offsets (tons) at a ratio of at least 1.15 to 1.00 based on the maximum allowable annual NO_x emissions rate (tons) for the entire facility (as indicated in Conditions 17, 29, 30, 38, and 39) when the reductions originate within the local domain of the Shenandoah National Park (SNP) airshed. This ratio shall be increased to at least 2.00 to 1.00 within the inner domain of the SNP airshed. These domains are shown on Figure 1 of this permit. This figure is based on Figure IV-8.a of the National Park Service report Assessment of Air Quality and Related Values in the Shenandoah National Park (May 2003). A listing of the counties comprising the local and inner domains is included as Appendix A to this permit.¶
¶
<#>The offsets shall be creditable (i.e., not otherwise required by law, regulation, or existing permit), quantifiable, permanent, and federally enforceable as defined in 40 CFR Part 51, App. S § II.A.12. The baseline for calculating the offsets shall be determined pursuant to the method set forth in 40 CFR Part 51, App. S § IV.C. ¶
¶
<#>In addition to satisfying the geographical and other requirements of Condition 23.a.i. of Level 1 above, the offsets shall be obtained as close as practicable to the Shenandoah National Park boundary.¶
¶
<#>The offsets shall be in effect prior to startup of the equipment listed in Condition 1.¶
¶
<#>Prior to commencing operation, the permittee shall provide to the DEQ official certification from the air pollution control agency that regulates each source which provides offsets, that the offsets meet the requirements of Condition 23.a.i. of Level 1, at a minimum documenting that the emissions reductions obtained as offsets are recognized by the agency as surpl ... [1]

a. The name of the fuel supplier;

b. The date on which the distillate oil was received;

c. The volume of distillate oil delivered in the shipment; and

d. The sulfur content of the distillate oil.

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 25, as applicable. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits. (9 VAC 5-80-1180)

29. **Emergency Generator and Emergency Fire Water Pump Operation** - The operation of the emergency generator (EG-1) and the emergency fire water pump (FWP-1) is limited to emergency situations. Emergency situations include emergency generator use to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted and emergency engine use to pump water in the case of fire or flood, etc. The emergency generator (EG-1) and the emergency fire water pump (FWP-1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 52 hours per year for each unit.
(9 VAC 5-80-1180 and 40 CFR 60.4211(e) and 40 CFR 60.4219)

30. **Emission Limits** - Emissions from the operation of the emergency fire water pump (FWP-1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	2.0 lbs/hr	0.5 tons/yr
Carbon Monoxide	1.7 lbs/hr	0.4 tons/yr
Volatile Organic Compounds	2.0 lbs/hr	0.5 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 26.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

31. **Emission Limits** - Emissions from the operation of the emergency generator (EG-1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	23.1 lbs/hr	5.8 tons/yr
Carbon Monoxide	12.6 lbs/hr	3.2 tons/yr
Volatile Organic Compounds	23.1 lbs/hr	5.8 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 27.
(9 VAC 5-50-260, 9 VAC 5-80-1180, and 9 VAC 5-80-1715)

32. **Emission Limits** - Emissions from the operation of the emergency fire water pump (FWP-1) shall not exceed the limits specified below:

	NSPS Standard
Particulate Matter (PM)	0.2 g/kW-hr
Non-Methane Hydrocarbons (NMHC) + Nitrogen Oxides	4.0 g/kW-hr
Carbon Monoxide	3.5 g/kW-hr

Compliance with these emission limits may be determined by keeping records of engine manufacture data indicating compliance with these emission limits.
(9 VAC 5-80-1180, 40 CFR 60.4205 (c), and 40 CFR 60.4211(c))

33. **Emission Limits** - Emissions from the operation of the emergency generator (EG-1) shall not exceed the limits specified below:

	NSPS Standard
Particulate Matter (PM)	0.2 g/kW-hr
Non-Methane Hydrocarbons (NMHC) + Nitrogen Oxides	6.4 g/kW-hr
Carbon Monoxide	3.5 g/kW-hr

Compliance with these emission limits may be determined by keeping records of engine manufacture data indicating compliance with these emission limits.
(9 VAC 5-80-1180, 40 CFR 60.4205 (b), and 40 CFR 60.4211(c))

34. **Visible Emission Limit** - Visible emissions from the emergency generator (EG-1) and the emergency fire water pump (FWP-1) shall not exceed 10 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-50-80 and 9 VAC 5-80-1180)

35. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the emergency generator (EG-1) and the emergency fire water pump (FWP-1) as described in Condition 1 shall be operated in compliance with the requirements outlined in 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, 9 VAC 5-60-90, 9 VAC 5-60-100, 40 CFR 60 Subpart IIII, and 40 CFR 63 Subpart ZZZZ)

<u>OPERATING/EMISSION LIMITATIONS – AUXILIARY BOILER (B-1) and FUEL GAS HEATER (GH-1)</u>

36. **Fuel** – The approved fuel for the auxiliary boiler (B-1) and the fuel gas heater (GH-1) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions (68°F and 29.92 in Hg) as specified in 40 CFR 72.2. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

37. **Fuel Throughput** – The auxiliary boiler (B-1) shall consume no more than 756.9 million cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

38. **Fuel Throughput** – The fuel gas heater (GH-1) shall consume no more than 446.8 million cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

39. **Emission Limits** - Emissions from the operation of the auxiliary boiler (B-1) shall not exceed the limits specified below:

Pollutant		
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu	4.24 tons/yr
Carbon Monoxide	0.037 lb/MMBtu	14.27 tons/yr
PM-10/PM-2.5	0.44 lbs/hr	1.93 tons/yr
Volatile Organic Compounds	0.47 lbs/hr	2.08 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition numbers 36 and 37.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

40. **Emission Limits** - Emissions from the operation of the fuel gas heater (GH-1) shall not exceed the limits specified below:

Pollutant		
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu	2.51 tons/yr
Carbon Monoxide	0.037 lb/MMBtu	8.43 tons/yr
PM-10/PM-2.5	0.39 lbs/hr	1.70 tons/yr
Volatile Organic Compounds	0.28 lbs/hr	1.23 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition numbers 36 and 38.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

41. **Visible Emission Limit** - Visible emissions from both the auxiliary boiler (B-1) and the fuel gas heater (GH-1) stacks shall not exceed 10 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-80-1180)

42. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the auxiliary boiler (B-1) and the fuel gas heater (GH-1) as described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.
(9 VAC 5-50-400, 9 VAC 5-50-410, 9 VAC 5-80-1180, and 40 CFR 60 Subpart Dc)

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

43. **CEMS** - Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2) and CO, in ppmvd corrected to 15 percent O_2, from each combined-cycle unit (T-1, T-2, & T-3). CEMS for NO_x shall meet the design specifications of 40 CFR 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the "Monitoring Requirements" in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 16, NO_x data and CO data shall each be reduced to 1-hour block averages. The relative accuracy test audit (RATA) of the NO_x CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-40, 9 VAC 5-80-420, 40 CFR 75, 40 CFR 60.13, and 40 CFR 60.4340(b))

44. **CEMS Performance Evaluations** - Performance evaluations of the NO_x and, if applicable, sulfur dioxide continuous monitoring systems shall be conducted in accordance with 40 CFR 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the DEQ, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30-day notification, prior to the demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the DEQ.
(9 VAC 5-50-40, 40 CFR 75, and 40 CFR 60.4345(a))

45. **CEMS Quality Control Program** - A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40, 40 CFR 60.13, 40 CFR 60.4345(e), and 40 CFR 60)

46. **Excess Emissions and Monitor Downtime for NO_x - Continuous Monitoring Systems** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 48 are defined as follows:

a. An excess emission is any unit operating period in which the one-hour average NO_x emission rate exceeds the applicable emission limit in Condition 16; and

b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee uses this information for compliance purposes.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

47. **Excess Emissions and Monitor Downtime for SO_2 - Continuous Monitoring Systems** Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

a. An excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit; and

b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4385)

48. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the DEQ of excess emissions from any process monitored by a continuous emission monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of calendar quarter. These reports shall include, but are not limited to, the following information:

a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, or malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments;

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report; and

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), 40 CFR 60.4375(a), and 40 CFR 60.4395)

49. **Excess Emissions for Continuous Monitoring Systems** – For purposes of identifying excess emissions:

a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations;

c. Correction of measured NO_x concentrations to 15 percent O_2 is not allowed; and

d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

RECORDS

50. **On Site Records -** The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. The records shall include, but are not limited to:

a. Annual throughput of natural gas to each CT (CT-1, CT-2, & CT-3), calculated monthly as the sum of each consecutive 12-month period.

b. Annual throughput of natural gas to each duct burner (DB1, DB2, & DB3) calculated monthly as the sum of each consecutive 12-month period.

c. Time, date and duration of each startup, shutdown, and malfunction period for each combined-cycle power generating unit (T-1, T-2, & T-3).

d. Annual number of startup and shutdown occurrences for each combined-cycle power generating unit (T-1, T-2, & T-3), calculated monthly as the sum of each consecutive 12-month period.

e. Records to verify sulfur content of pipeline natural gas as required in Condition 15.

f. Continuous records of heat input for each combined-cycle power generating unit (T-1, T-2, & T-3).

g. Continuous records of power output from combined-cycle power generating units (T-1, T-2, & T-3) and the steam turbine generator(s).

h. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 17, 30 and 31, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the DEQ.

i. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions.

j. Annual hours of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for emergency purposes, calculated monthly as the sum of each consecutive 12-month period.

k. Records of time, date, and duration of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for maintenance checks and readiness testing and the operational status of each combined-cycle unit (T-1, T-2, and T-3) during those maintenance checks and readiness testing.

l. Annual hours of operation for the emergency fire water pump (FWP-1) and the emergency generator (EG-1) for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period.

m. All fuel supplier certifications for the emergency units (FWP-1 & EG-1).

n. Records of engine manufacturer data as required by Conditions 32 and 33.

o. Operation and control device monitoring records for each SCR system and each oxidation catalyst.

p. Records for each combined-cycle unit (T-1, T-2, and T-3) showing steady-state vs. non-steady-state operation during a given hour, the ammonia slip monitoring plan, and the ammonia slip monitoring results as required by Condition 21.

q. Scheduled and unscheduled maintenance and operator training.

r. Results of all stack tests, visible emission evaluations, visible emission inspection results, and performance evaluations.

s. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the fuel gas heater (GH-1) calculated monthly as the sum of each consecutive 12-month period.

t. Records of good combustion practices for the auxiliary boiler (B-1) and the fuel gas heater (GH-1) as required by Condition 12.

u. Records to verify sulfur content of pipeline natural gas as required in Condition 36.

v. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 39 and 40, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the DEQ.

w. Records related to NO_x offsets as required by Condition 24 d.

x. Records related to the CEMS quality control program as required by Condition 45.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50)

TESTING

51. **Testing/Monitoring Ports -** The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing stack or duct that is free from cyclonic flow. Test ports shall be provided in accordance with the applicable performance specification (reference 40 CFR Part 60, Appendix B). (9 VAC 5-50-30 F)

52. **Initial Performance Test – Combustion Turbines -** Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for the following pollutants using the specified methods:

Pollutant	Test Method
Carbon Monoxide (CO)	40 CFR 60, Appendix A, Method 10
Volatile organic compounds (VOC)	40 CFR 60, Appendix A, Method 25A
PM-10 (All particulate matter shall be considered PM-10 and shall include condensables)	40 CFR 60, Appendix A, Methods 5 or 17 and 19, and 40 CFR 51, Appendix M, Method 202

Tests shall be conducted to determine compliance with the emission limits contained in Condition 16. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. CO, VOC and PM-10 emissions shall be determined at each of the operating conditions indicated for each pollutant contained in Condition 16. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion and shall conform to the test report format enclosed with this permit.

The permittee shall perform an initial stack test for PM-2.5 in the time frames as required for testing the other pollutants in this condition if a test method for PM-2.5 has received final approval by the USEPA or DEQ at that time. If a test method for PM-2.5 has not received final approval by the USEPA or DEQ at the time initial testing as required in this condition is to be conducted, the permittee shall perform initial stack testing for PM-2.5 within 60 days of final approval of a test method by USEPA or DEQ, or as required by the DEQ. This permit limits for PM-2.5 may be changed in accordance with 9 VAC 5-80-1925, to reduce the emission limit based on results from stack testing as required in this condition.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

53. **Initial Performance Test – Combustion Turbines** – Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for oxides of nitrogen (as NO_2) to determine compliance with the limits contained in Condition 16 as follows:

a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the NO_x concentration (in ppm). Sampling traverse points for NO_x and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

b. Notwithstanding Condition 53.a. above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met: The permittee may perform a stratification test for NO_x and diluent pursuant to the procedures specified in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

i. If each of the individual traverse point NO_x concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent O_2 from the mean for all traverse points, three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall) may be used. The three points must be located along the measurement line that exhibited the highest average NO_x concentration during the stratification test; or

ii. The permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent O_2 from the mean for all traverse points.

c. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Testing may be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total NO_x emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable emission limit in Condition 16 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_x emission rate at each tested level meets the applicable emission limit in Condition 16.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following as alternatives to the reference methods and procedures specified in this condition:

i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

ii. Compliance with the applicable emission limit in Condition 16 is achieved if the arithmetic average of all of the NO_x emission rates for the RATA runs, expressed in units of ppm, does not exceed the emission limit.

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405, and 40 CFR 60.4400)

54. **Initial Performance Test – Combustion Turbines** – Initial performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 16. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in ppm). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8, and 40 CFR 60.4415)

55. **Initial Performance Test – Auxiliary Boiler and Fuel Gas Heater** – Initial performance tests shall be conducted on the auxiliary boiler (B-1) and the fuel gas heater (GH-1) for NO_x and CO to determine compliance with the emission limits contained in Conditions 39 and 40. The tests shall be performed, reported, and demonstrate compliance within 60 days after the boiler or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial startup. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion but no

later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

56. **Compliance Demonstration – Duct Burners** – The permittee shall determine compliance with the NO_x emission limits in Condition 19 by complying with the NO_x emission limits contained in Condition 16.
(9 VAC 5-50-30, 9 VAC 5-50-410, and 40 CFR 60.4400 (b)(2))

57. **Visible Emissions Evaluation – Combustion Turbines** - Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combined-cycle generating unit stack. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating conditions for which emissions tests are required for the stack tests contained in Condition 52. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit.

Should conditions prevent concurrent opacity observations, the DEQ shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the DEQ, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

58. **Visible Emissions Evaluation - Auxiliary Boiler and Fuel Gas Heater** - Concurrently with the initial performance tests in Condition 55, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the auxiliary boiler (B-1) and fuel gas heater (GH-1). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. Each evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler or fuel gas heater, as applicable, will be operated but in no event later than 180 days after start-up of the unit.

Should conditions prevent concurrent opacity observations, the DEQ, shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the DEQ,

within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

CONTINUING COMPLIANCE DETERMINATION

59. **Annual Performance Test – Combustion Turbines** – Annual performance tests shall be conducted on each combined-cycle unit (T-1, T-2, & T-3) for sulfur dioxide (SO_2) to determine compliance with the limits contained in Condition 16. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

    a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

    b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

    c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

    The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the DEQ. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the DEQ, within 45 days after test completion and shall conform to the test report format enclosed with this permit.
    (9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.4415(a))

60. **Stack Tests** - Upon request by the DEQ, the permittee shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.
(9 VAC 5-50-30 G)

61. **Visible Emissions Evaluation – Combustion Turbines** – The permittee shall conduct visible emission inspections on each combined-cycle generating unit (T-1, T-2, & T-3) stack in accordance with the following procedures and frequencies:

a. At a minimum of once per week, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed the applicable standard, the VEE shall be conducted for a total of 60 minutes.

b. If visible emissions inspections conducted during 12 consecutive weeks show no visible emissions for a particular unit stack, the permittee may reduce the monitoring frequency to once per month for that unit stack. Anytime the monthly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per week for that stack.

c. All visible emission inspections, observations and VEE results shall be recorded.

(9 VAC 5-50-20)

62. **Visible Emissions Evaluation – Auxiliary Boiler and Fuel Gas Heater** – The permittee shall conduct visible emission inspections on the auxiliary boiler (B-1) and the fuel gas heater (GH-1) stacks in accordance with the following procedures and frequencies:

a. At a minimum of once per month, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed 10 percent opacity, the VEE shall be conducted for a total of 60 minutes.

b. All visible emissions inspections shall be performed when the boiler or fuel gas heater (as applicable) is operating.

c. If visible emissions inspections conducted during 12 consecutive months show no visible emissions, the permittee may reduce the monitoring frequency to once per quarter. Anytime the quarterly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per month.

d. All visible emission inspections, observations and VEE results shall be recorded.

(9 VAC 5-50-20)

NOTIFICATIONS

63. **Initial Notifications** - The permittee shall furnish written notification of the following to the DEQ:

    a. The actual date on which construction of the electric power generation facility commenced, within 30 days after such date.

    b. The anticipated start-up date of the electric power generation facility, postmarked not more than 60 days nor less than 30 days prior to such date.

    c. The actual start-up date of the electric power generation facility, within 15 days after such date.

    d. The actual date on which construction of the auxiliary boiler commenced, within 30 days after such date.

    e. The actual start-up date of the auxiliary boiler, within 15 days after such date.

    f. The actual date on which construction of the fuel gas heater commenced, within 30 days after such date.

    g. The actual start-up date of the fuel gas heater, within 15 days after such date.

    h. The anticipated date of continuous monitoring system performance evaluations, postmarked not less than 30 days prior to such date.

    i. The anticipated date of performance tests of the electric power generation facility, postmarked at least 30 days prior to such date.

    j. The actual dates on which construction of the emergency generator and emergency fire water pump commenced, within 30 days after such dates.

    k. The actual start-up dates of the emergency generator and emergency fire water pump, within 15 days after such dates.

Copies of the written notifications referenced in items a through i above are to be sent to:

Associate Director
Office of Air Enforcement (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

64. **Permit Invalidation** - This permit to construct and operate an electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction is not commenced within 18 months from the date of this permit.

    b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time. This provision does not apply to the period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date

    DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified.
    (9 VAC 5-80-1210 and 9 VAC 5-80-1985)

65. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

    a. Knowingly makes material misstatements in the application for this permit or any amendments to it;

    b. Fails to comply with the conditions of this permit;

    c. Fails to comply with any emission standards applicable to a permitted emissions unit;

    d. Causes emissions from this facility which result in violations of, or interferes with the attainment and maintenance of, any ambient air quality standard; or

e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

(9 VAC 5-80-1210 F and 9 VAC 5-80-1985)

66. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130)

67. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E)

68. **Record of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180 J)

69. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the DEQ, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of the discovery. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the DEQ, in writing.
(9 VAC 5-20-180 C)

70. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

71. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the DEQ, of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240 and 9 VAC 5-80-1975)

72. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-170-160)

STATE-ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-60-300, *et. seq.* Neither their inclusion in this Prevention of Significant Deterioration Permit nor any resulting public comment period make these terms federally enforceable.

73. **Emission Limits -** Emissions from the electric power generation facility shall not exceed the limits specified below:

Pollutant	CAS #	Hourly Limit	Annual Limit
Acrolein	107-02-8	0.0406 lbs/hr	0.176 tons/yr
Formaldehyde	50-00-0	1.48 lbs/hr	6.34 tons/yr
Cadmium	7440-43-9	0.0115 lbs/hr	0.00551 tons/yr
Chromium	7440-47-3	0.0146 lbs/hr	0.00702 tons/yr
Nickel	7440-02-0	0.0219 lbs/hr	0.0105 tons/yr

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-60-320, 9 VAC 5-80-1180, and 9 VAC 5-80-1625 G)

74. **Emission Limits** – The permittee shall determine compliance with the toxic pollutants emission limits in Condition 73 as follows:

a. To calculate hourly toxic compound emissions from the electric power generation facility:

$$E_t = \left(\sum_{i=1}^{n} F_i C_i\right)\left(\frac{100 - CE}{100}\right)$$

.... Equation 1

Where:

E_t = Emission rate of toxic compound (t) (lbs/hr)

F_i = Emission factor of toxic compound (t) for each unit (i) utilized during the time period (lb/MMBtu)

C_i = Capacity of each unit (i) utilized during the time period (MMBtu/hr)

CE = Control efficiency of volatile toxic compounds by the oxidation catalyst (%) [30 is accepted reduction unless records demonstrate a different value]

b. To calculate annual toxic compound emissions from the electric power generation facility:

$$E_t = \left(\sum_{i=1}^{n} F_i C_i T_i\right)\left(\frac{100 - CE}{100}\right)\left(\frac{1ton}{2000lb}\right)$$

.... Equation 2

Where:

E_t = Emission rate of toxic compound (t) (tons/year)

F_i = Emission factor of toxic compound (t) for each unit (i) utilized during the time period (lb/MMBtu)

C_i = Capacity of each unit (i) utilized during the time period (MMBtu/hr)

T_i = Hours of operation for each unit (i) utilized during the time period (hours)

CE = Control efficiency of volatile toxic compounds by the oxidation catalyst (%) [30 is accepted reduction unless records demonstrate a different value]

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1625 G)

75. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. These records shall include, but are not limited to:

a. Total hours that each unit operates on a monthly basis.

b. Average hourly, monthly and annual emissions (in pounds and tons) of each toxic compound listed in Condition 73. Toxic compound emissions shall be calculated as shown in Condition 74. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.

These records shall be available for inspection by the DEQ and shall be current for at least the most recent five years.
(9 VAC 5-80-1180, 9 VAC 5-50-50, and 9 VAC 5-80-1625 G)

SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certification date)
* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates
* 4. Pollutants tested
5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions
* 4. Description of collected samples, to include audits when applicable
5. Discussion of errors, both real and apparent

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process and control equipment data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

Appendix
* 1. Process data and emission results example calculations
2. Raw field data
* 3. Laboratory reports
4. Raw production data
* 5. Calibration procedures and results
6. Project participants and titles
7. Related correspondence
8. Standard procedures

* Not applicable to visible emission evaluations.

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Source Reductions and Emission Offsets – For the purposes of mitigating potential air quality impacts on Air Quality Related Values (AQRVs) at the Shenandoah National Park Class I Area in Virginia, including visibility and acid deposition, the permittee shall implement the following:

Level 1

Acid Deposition Offsets – The permittee shall secure a reduction in emissions contributing to acid deposition from a source or sources in the manner prescribed as follows:

At a minimum, the permittee shall secure NO_x emissions offsets (tons) at a ratio of at least 1.15 to 1.00 based on the maximum allowable annual NO_x emissions rate (tons) for the entire facility (as indicated in Conditions 17, 29, 30, 38, and 39) when the reductions originate within the local domain of the Shenandoah National Park (SNP) airshed. This ratio shall be increased to at least 2.00 to 1.00 within the inner domain of the SNP airshed. These domains are shown on Figure 1 of this permit. This figure is based on Figure IV-8.a of the National Park Service report Assessment of Air Quality and Related Values in the Shenandoah National Park (May 2003). A listing of the counties comprising the local and inner domains is included as Appendix A to this permit.

The offsets shall be creditable (i.e., not otherwise required by law, regulation, or existing permit), quantifiable, permanent, and federally enforceable as defined in 40 CFR Part 51, App. S § II.A.12. The baseline for calculating the offsets shall be determined pursuant to the method set forth in 40 CFR Part 51, App. S § IV.C.

In addition to satisfying the geographical and other requirements of Condition 23.a.i. of Level 1 above, the offsets shall be obtained as close as practicable to the Shenandoah National Park boundary.

The offsets shall be in effect prior to startup of the equipment listed in Condition 1.

Prior to commencing operation, the permittee shall provide to the DEQ official certification from the air pollution control agency that regulates each source which provides offsets, that the offsets meet the requirements of Condition 23.a.i. of Level 1, at a minimum documenting that the emissions reductions obtained as offsets are recognized by the agency as surplus (not otherwise required by regulation), permanent, and federally enforceable. The document shall state that the emissions reduction has not been and will not be credited toward another reduction requirement. The facility shall not commence operation until the DEQ has approved in writing the certification and/or other documentation submitted by the permittee pursuant to this subsection as satisfying the requirements of Condition 23.a.i. of Level 1. The offsets procured from World Kitchen, Inc. in

Martinsburg, West Virginia, and approved by DEQ in a letter dated 11/13/07 may be applied toward the total offset requirement in Condition 23.a.i. of Level 1.

The permittee shall maintain at the permitted facility a copy of the following:

Identification of each source from which offsets were obtained. Identification shall include the name, address and Universal Transverse Mercator (UTM) coordinates of the facility and any identification number assigned to the facility by the air pollution control authority that regulates it.

Certification document from each air pollution control agency required by Condition 23.a.iii. and any supporting documentation.

<u>Level 2</u>

If the permittee is unable to secure adequate offsets using the provisions of Condition 23.a.i. of Level 1, then the permittee shall develop or cause to be developed economically and environmentally reasonable project or projects that generate oxides of nitrogen emission reductions from physical and/or operational changes at one or more other facilities. These Level 2 reductions shall be in addition to any reductions obtained in Level 1 and shall equate to the total reduction requirements in Level 1 when summed with those Level 1 reductions. Such Level 2 mitigation shall be within the geographic area and in accordance with the emission reduction ratios defined in Level 1, above, of this permit based on the location of the facility from which the emission reduction is generated. Level 2 mitigations must be achieved and documented within 18 months of the date Level 2 action was initiated. Level 2 mitigation must also be obtained prior to the initial operation of the Warren County facility. To be eligible for credit as mitigation, Level 2 mitigation obtained cannot be mandated as part of:

Legal action (such as a Consent Decree), or

A State Implementation Plan for the Regional Haze Rule (such as Best Available Retrofit Technology), or

Emission reductions required in a non-attainment area, or

A source fulfilling their obligation under the Clean Air Interstate Rule.

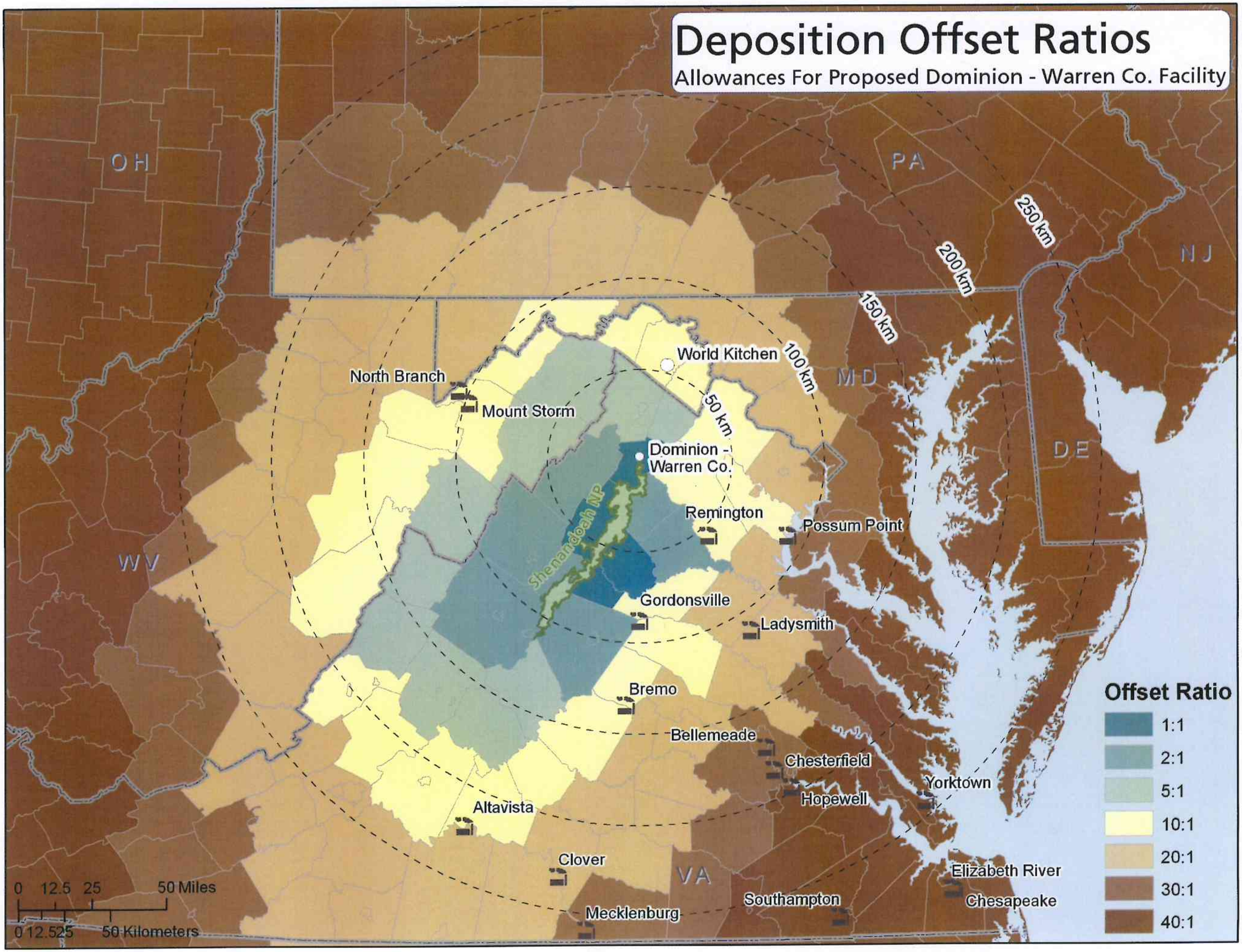
No Level 2 mitigation obtained as a part of this permit can be sold or traded to another party, or used to fulfill other Federal or State emission reduction requirements, or be used for emission netting by the facility making the Level 2 mitigation. The permittee shall demonstrate that the Level 2 mitigation is enforceable with documentation provided by the appropriate Federal or State agency implementing the air quality program where the Level 2 mitigation occurs. The permittee may claim credit if it becomes economically and environmentally reasonable to install additional equipment or operations that control actual oxides of nitrogen emissions at another facility beyond the level required under the applicable regulatory or legal requirements in effect as of December 31, 2010.

Any permanent emission reductions will require documentation provided by the appropriate Federal or State agency implementing the air quality program where the emission reductions occurred.

Reporting Requirements

The permittee shall submit reports, as necessary, detailing and discussing the reductions occurring as a result of actions taken within each Level. All reports shall be sent to the Director, Valley Regional Office and

Superintendent
Shenandoah National Park
3655 U.S. Highway 211 East
Luray, VA 22835


Deposition Offset Ratios
Allowances For Proposed Dominion - Warren Co. Facility
OH
PA
NJ
MD
DE
WV
VA
250 km
200 km
150 km
100 km
50 km
World Kitchen
North Branch
Mount Storm
Dominion -
Warren Co.
Shenandoah NP
Remington
Possum Point
Gordonsville
Ladysmith
Bremo
Bellemeade
Chesterfield
Hopewell
Yorktown
Altavista
Clover
Mecklenburg
Southampton
Elizabeth River
Chesapeake
Offset Ratio
1:1
2:1
5:1
10:1
20:1
30:1
40:1
0 12.5 25 50 Miles
0 12.525 50 Kilometers

Attachment B: List of Geographic Locations From Which Allowances May Be Obtained

1:1 Locations:

Virginia Counties:	Warren, Page, Madison, and Greene

2:1 Locations:

Virginia Counties:	Shenandoah, Rockingham, Augusta, Albemarle, Culpeper, and Rappahannock
Virginia Cities:	Harrisonburg, Staunton, Waynesboro, and Charlottesville

5:1 Locations:

Virginia Counties:	Frederick, Highland, Bath, Rockbridge, Amherst, and Nelson
Virginia Cities:	Winchester, Lexington, and Buena Vista
West Virginia Counties:	Hampshire, Hardy, and Pendleton

10:1 Locations:

Virginia Counties:	Loudoun, Prince William, Fauquier, Orange, Louisa, Fluvanna, Buckingham, Appomattox, Campbell, Bedford, Botetourt, and Alleghany
Virginia Cities:	Lynchburg, Bedford, and Covington
West Virginia Counties:	Jefferson, Berkeley, Morgan, Mineral, Grant, Tucker, Randolph, and Pocahontas
Maryland Counties:	Allegany

20:1 Locations:

Virginia Counties:	Fairfax, Stafford, Spotsylvania, Caroline, Hanover, Goochland, Powhatan, Amelia, Cumberland, Prince Edward, Nottoway, Lunenburg, Charlotte, Halifax, Pittsylvania, Henry, Patrick, Floyd, Franklin, Montgomery, Roanoke, Craig, and Giles
Virginia Cities:	Fairfax, Manassas Park, Manassas, Fredericksburg, Danville, Martinsville, Roanoke, and Salem
West Virginia Counties:	Monroe, Greenbrier, Nicholas, Webster, Braxton, Lewis, Upshur, Barbour, Harrison, Marion, Taylor, Preston, and Monongalia
Maryland Counties:	Garrett, Washington, Frederick, and Montgomery

Pennsylvania Counties: Greene, Fayette, Somerset, Bedford, Fulton, and Franklin

30:1 Locations:

Virginia Counties:	King George, Essex, King William, Henrico, Chesterfield, Dinwiddie, Brunswick, Mecklenburg, Carroll, Grayson, Wythe, Pulaski, and Bland
Virginia Cities:	Richmond, Galax, and Radford
West Virginia Counties:	Mercer, Summers, Raleigh, Fayette, Clay, Gilmer, and Doddridge
Pennsylvania Counties:	Washington, Allegheny, Westmoreland, Armstrong, Indiana, Cambria, Blair, Cumberland, and Adams
Maryland Counties:	Carroll, Howard, Prince George's, and Charles

40:1 Locations:

All other jurisdictions within the boundaries of Virginia, North Carolina, Tennessee, Kentucky, West Virginia, Ohio, Pennsylvania, New Jersey, Delaware, and Maryland